4. Indexing Review

Technological and Data Changes

The uniform oil lease equipment design adopted in 1976 was the basic criterion for oil lease equipment cost estimates. Revisions have been made to stay current with engineering and competitive practices. Individual component prices were combined into one price for a group of equipment, as necessary, to assure confidentiality of prices. Appendix Tables A15 through A18 contain detailed equipment lists of representative wells in west Texas for each depth, reflecting all changes made to date.

Standardization of the data used has evolved during the past 23 years. Improved methods for measuring various contractor costs were used and applied to previous estimates. The gas lease equipment designs were made in 1980 and the equipment and operating components were priced back through 1976. There have been no recent design changes for gas equipment. A typical design is shown in Appendix Table H11, which contains a list of equipment for a 12,000-foot gas well producing 1 MMcf per day in west Texas.

Estimated preliminary costs for the prior report were revised to reflect new data. Some of these changes and factors were:

- New projections of *Joint Association Survey* (JAS) data for west Texas were made to estimate 1999 drilling costs.
- Regional wellhead gas prices for 1996-1999 are from the latest edition of the EIA Natural Gas Annual (DOE/EIA-0131 99). These 1999 prices are estimated.

Primary Oil Recovery

Leases for oil wells were assumed to consist of 10 wells producing by artificial lift into a centrally located tank battery. The depths of all wells on the leases were 2,000, 4,000, 8,000, or 12,000 feet.

Costs were determined for new equipment capable of producing 200 barrels of liquid per day per well for onshore primary operations. Tubing costs were included for information only. Note that care must be exercised when combining these equipment costs with drilling costs to obtain total lease development and equipment costs, because most drilling cost estimates include tubing costs. The artificial lift selected was dependent upon the type of lift found to be dominant for each depth in each region. The two types of prime movers considered were electric motors and natural gas engines. Table 22 details the type of lift and prime mover

Table 22. Type of Artificial Lift and Prime Mover Used for Each Depth and Region

Region	Type of Lift	Prime Mover	Type of Lift	Prime Mover
	2,000-Foot Wells		4,000-Foot Wells	
California	Rod	Motor	Rod	Motor
Oklahoma	Rod	Engine	Rod	Engine
South Louisiana	Rod	Engine	Gas	Engine
South Texas	Rod	Engine	Gas	Engine
West Texas	Rod	Engine	Rod	Engine
Rocky Mountains	Rod	Motor	Rod	Motor
	8,000-Foot Wells		12,000-Foot Wells	
California	Hydraulic	Motor	Hydraulic	Motor
Oklahoma	Hydraulic	Engine	Hydraulic	Engine
South Louisiana	Gas	Engine	Hydraulic	Engine
South Texas	Gas	Engine	Hydraulic	Engine
West Texas	Rod	Engine	Hydraulic	Engine
Rocky Mountains	Rod	Motor	Hydraulic	Motor

Source: Energy Information Administration, Office of Oil and Gas.

used in each region and depth. Annual operating costs were estimated for daily production rates of 100 barrels of liquid (90 barrels of oil) per day per well for each depth in each region of operation.

Secondary Oil Recovery

Costs for secondary oil recovery in west Texas were calculated for wells producing from depths of 2,000, 4,000, and 8,000 feet. Each lease had 10 producing wells, 11 injection wells, and 1 disposal well. Additional costs included those for water supply wells, water storage tanks, injection plant, filtering systems, and injection lines. Equipment was designed to handle 350 barrels of liquid per day per producing well. Gas engines used in primary operations were replaced by electric motors for secondary oil recovery. Some equipment for primary oil production was replaced with larger equipment to accommodate the increased liquid volumes assumed for secondary recovery production. Increases in operational costs for secondary oil recovery are indicated for the increased liquid lift of 290 barrels of liquid (90 barrels of oil) per day per producing well and the water injection system. Additional equipment costs are presented in Appendix Tables A9, A10, and A11, and direct annual operating costs are presented in Tables A12, A13, and A14.

Offshore Gas and Primary Oil Recovery

Equipment and operating costs for the offshore Gulf of Mexico were estimated for 12- and 18-slot platforms containing one dually completed well in each slot. Maximum crude oil production was assumed to total 11,000 barrels of oil per day from wells on each platform. Maximum associated gas production was assumed to be 40 MMcf cubic feet of gas per day per platform. Note that the balance between gas and oil is weighted more heavily toward gas in offshore operations than in onshore leases. Operating costs were derived for platforms assumed to be 50, 100, and 125 miles from shore corresponding to water depths of 100, 300, and 600 feet, respectively. Meals, platform maintenance, helicopter and boat transportation

of personnel and supplies, communication costs, insurance costs for platform and production equipment and administrative expenses are included in normal production

of oil and gas in offshore operations but not in onshore leases. Operating costs were derived for platforms assumed to be 50, 100, and 125 miles from shore corresponding to water depths of 100, 300, and 600 feet, respectively. Meals, platform maintenance, helicopter and boat transportation of personnel and supplies, communication costs, insurance costs for platform and production equipment and administrative expenses are included in normal production

expenses. Crude oil and natural gas transportation costs to shore were excluded, as were water disposal costs.

Gas Recovery

Leases for gas wells were assumed to consist of one well producing into an onsite separator with two storage tanks (a lease condensate sales tank and a water storage tank). Line heaters, dehydration units, and methanol injectors were included where needed. It was assumed that any compression or gas treatment would be provided by the first purchaser. The cost data presented were based on the installation of new equipment and included items needed from the wellhead to the inlet on the meter run for the gas stream and through the tank for the liquid streams. Downhole tubing costs were not included, nor were equipment for disposal of produced water above nominal amounts of water entrained in the gas stream. Gas production rates of 50, 250, 500, 1,000, 5,000, and 10,000 Mcf of gas per day and well depths of 2,000, 4,000, 8,000, 12,000, and 16,000 feet were the assumed volume and depth divisions for the cost determinations. These volumes were selected because of different processing equipment requirements for each of these flow rates. Production records were used to determine the average production rate for each depth in each region. The equipment and operating costs for each of these average production rates were then calculated. For a broader view of each flow rate in each region at each depth, the equipment and operating costs of the next higher and/or lower rates are shown. Costs were calculated for equipping gas wells at producing rates of 50 Mcf per day even though a new well coming onstream at this rate may never reach payout. This low rate of flow was selected to identify costs of production from stripper gas wells. Flow rates above 10 MMcf per day usually require custom design of equipment and are not priced in this report.

The depths of 2,000, 4,000, 8,000, and 12,000 feet were chosen to be compatible with data provided for oil production. An additional depth of 16,000 feet was added for gas equipment and operations because there was significant gas production from this depth in some regions studied.